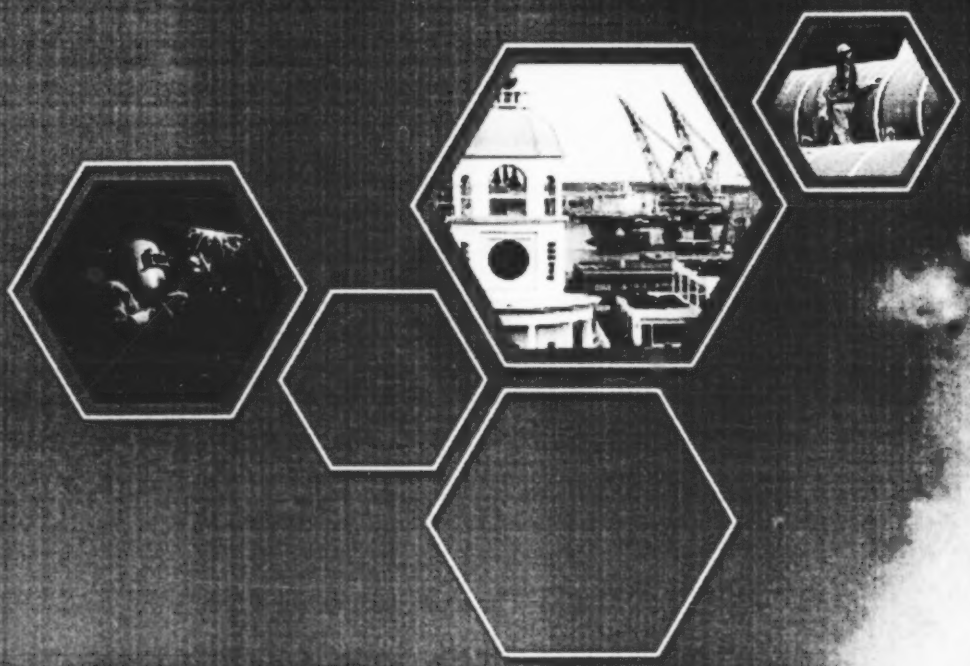
Nova Scotia Prospect Profile
Offshore 2005



Energy

106-0 5734 /

Conversion Chart

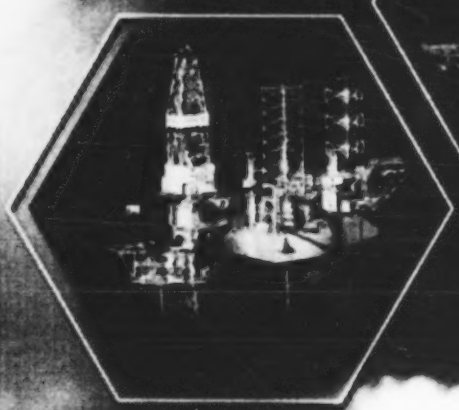
1 mile = 1.6093 km

1 sq mile = 2.5898 sq km

1 cubic foot = 0.0283 cubic metres

1 million cubic feet = 28,317 cubic metres

1 trillion cubic feet = 28.317 x 10^9 cubic metres



Information as of December

Introduction

Introduction

With a competitive fiscal regime, proximity to North American markets and potential for viable commercial reserves, Nova Scotia offers a competitive advantage in offshore exploration and development.

Add to that our commitment to streamlining regulatory processes and a business community that is gaining a worldwide reputation for excellence in engineering, fabrication and supply and services; it's easy to see why Nova Scotia continues to attract attention.

The Nova Scotia Prospect Profile Offshore 2004 provides you with a glimpse of the opportunities and potential in Nova Scotia's offshore.

Whether you're interested in resource potential in the deep water, want to find out what's new in the Carbonate Bank and Scotian Shelf, or want to know how you can be a part of the exploration and development of offshore oil and natural gas in Nova Scotia, this booklet is for you.

The Nova Scotia Department of Energy

The Department of Energy promotes, supports and coordinates, administers and gives policy advice on the development of a prosperous, clean, efficient, and sustainable energy industry in Nova Scotia. Our mission is to help Nova Scotians build a better future by ensuring responsible resource management of Nova Scotia's energy resources, and by maximizing financial, economic, industrial, and employment benefits that flow from the development and use of energy resources.

The Department is responsible for the development of policy, legislation, and regulations for the exploration and development of the province's offshore and onshore petroleum resources, which includes the administration of the royalty regulations and agreements. In the onshore, the Department administers the granting of petroleum rights and coordinates the regulation of exploration activity. The Canada-Nova Scotia Offshore Petroleum Board regulates day-to-day offshore petroleum activity while the Department promotes Nova Scotia's onshore and offshore petroleum potential.

Visit our web site at **www.gov.ns.ca/energy** for additional information.

The Canada-Nova Scotia Offshore Petroleum Board

The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) regulates petroleum activities offshore Nova Scotia in an efficient, fair and competent manner. The Board is the independent joint agency of the Governments of Canada and Nova Scotia established pursuant to the federal **Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act** and the provincial **Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act**. It is responsible for regulating petroleum affairs and safe practices offshore Nova Scotia.

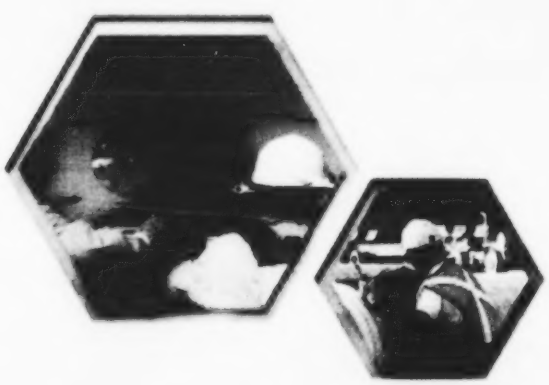
The Board's principal responsibilities include:

- ensuring the safe conduct of offshore operations
- protection of the environment during offshore petroleum activities
- management of offshore oil and gas resources
- review of industrial benefits and employment opportunities
- issuance of licences for offshore exploration and development
- resource evaluation, data collection and distribution.

Visit them at **www.cnsopb.ns.ca**

Rights Issuance

- Crown Reserve Lands
- Call for Nominations
- Call for Bids/Public Consultation
- Exploration Licence
- Significant Discovery Licence
- Production Licence



Rights Issuance

Petroleum rights offshore Nova Scotia are managed by the Canada-Nova Scotia Offshore Petroleum Board (the Board) and are based on the *Canadian Petroleum Resources Act* model. The main components include:

Crown Reserve Lands

These are lands over which no interest has been issued. Interests in Crown Reserve lands are issued through a competitive bidding process. Details of the rights issuance process are described in the Board publication entitled, **"Guidelines On the Issuance Of Exploration Licences."**

Call for Nominations

The current policy of the Board is to rely on industry to nominate lands. Nominations can be submitted at anytime; however, the Board has established a semi-annual cycle for a June and December Call for Bids. The closing date to nominate lands for consideration in the June and December Call for Bids is March 31st and September 30th, respectively.

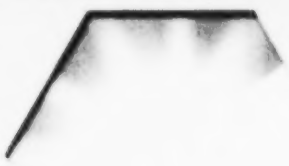
Call for Bids/Public Consultation

Once the land has been nominated, the Board will meet and commence the process to issue a Call for Bids and request for public comments. The Call for Bids specifies;

- the type of interest to be issued (Exploration Licence (EL), Significant Discovery Licence (SDL) or Production Licence (PL);
- the terms and conditions of the interest:
- the form and manner in which the bid is to be submitted;
- a closing date (120 days from issuance); and
- the sole criterion that the Board will apply in assessing bids submitted in response to the Call.

All bids for Exploration Licences (EL) are evaluated on the basis of total work expenditures or the amount of money to be committed on exploration on the subject lands during Period I of the term. In addition, the Board invites written public comment, and after reviewing both the comments and bids, will determine whether or not to issue an EL. This is not an automatic decision.

Where Significant Discovery Licences (SDL) or Production Licences (PL) are posted, the Board may specify that cash bidding will be used as the sole criterion. Bids of less than $1 million CDN are not considered.



Within 15 days of being notified the bid has been accepted, the successful bidder must provide a work deposit equal to 25% of the work expenditure bid. The deposit is refunded annually in proportion to the amount of the work expenditure bid that is expended in that year as determined in accordance with the allowable expenditures included. Any work deposit balance remaining at the end of the specified period is forfeited.

Exploration Licence (EL)

This is the licence (EL) issued to an explorer for a term up to nine years on lands that do not contain significant discoveries or, in effect, wildcat acreage. The Exploration Licence (EL) specifies the owner must start drilling a well before the first period expires. If this is not done, the EL terminates at the end of the first period. There are no rentals paid in Period I. Period II rentals are refundable against allowable expenditures.
The EL confers the following:

- the right to explore the subject lands;
- the exclusive right to drill and test for petroleum on those lands; and
- the exclusive right to obtain a Production Licence in respect of the subject lands.

Significant Discovery Licence (SDL)

The SDL is an intermediate interest designed to maintain an explorer's rights during the period between the first discovery and eventual production. After a discovery has been made, the explorer may apply to have it declared an SDL defined by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons and suggests that the accumulation of hydrocarbons has potential for sustained production. Once a Significant Discovery (SD) has been declared, the holder of the EL may then apply for an SDL for all portions of the significant discovery area located on the EL. An SDL confers the same rights as an EL but has an indefinite term.

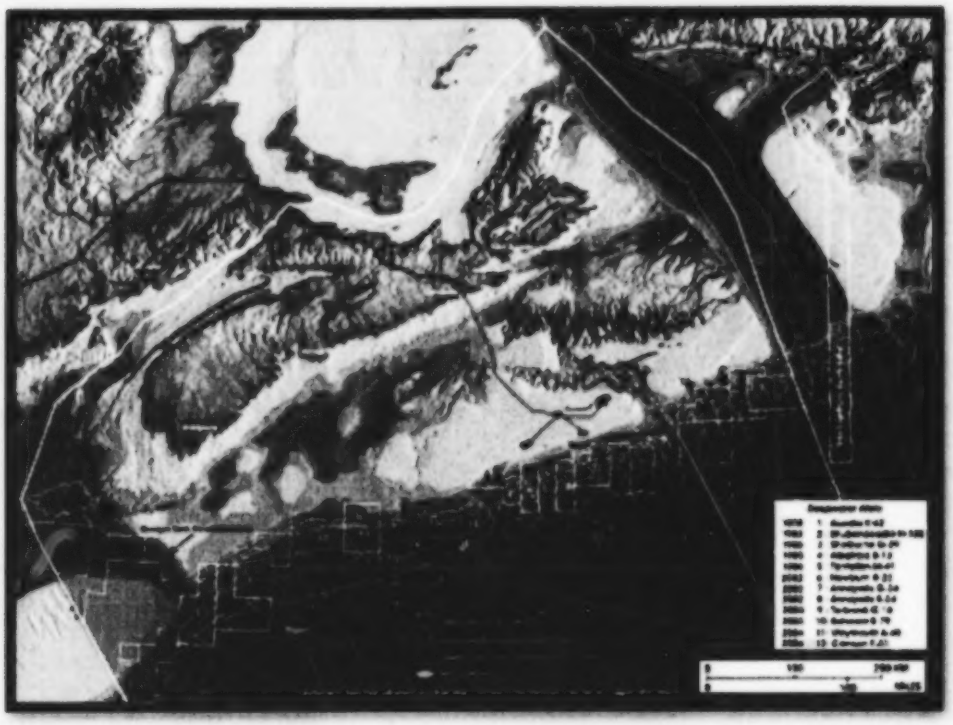
When a declaration of SD extends to Crown Reserve Lands, these lands may be posted for bid and an SDL may be issued to the winning bidder.

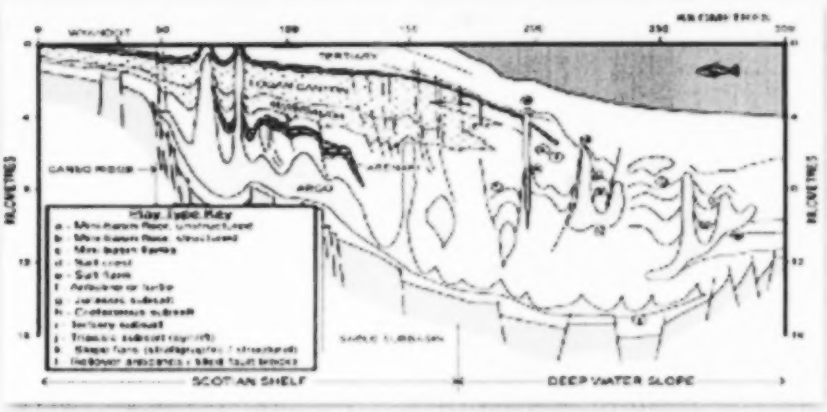
Production Licence (PL)

Production rights are conferred by the issuance of a Production Licence (PL), which may be issued in respect of any portion of the offshore area subject to a commercial discovery. A commercial discovery is one that has demonstrated it contains reserves that will justify the investment of capital and effort to bring the discovery to production. No PL may be held by any person other than a corporation incorporated in Canada. A PL has a term of 25 years but may be extended if commercial production is continuing or is likely to recommence.

For further assistance, contact the Manager of Resources & Rights at the Board (902.422.5588) or **www.cnsopb.ns.ca**

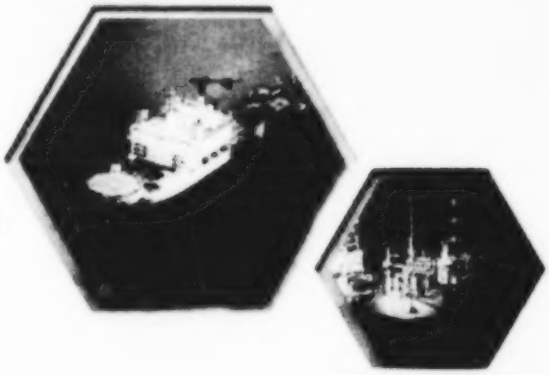
Deep Water





15-41 Tcf

- 31,000 mi^2
- Multiple untested play types
- 100's of features



Deep Water Slope

Nova Scotia's offshore oil and gas sector has undergone a major resurgence since the late 1990's. Exploration success in the deep water passive margins around the world has resulted in companies bringing that experience to offshore Nova Scotia to begin the process of evaluating the potential. The last few rounds of lands awarded have been over acreage that lies in water depths greater than 3200 ft. Industry has committed to spend more than $600 million in new exploration ventures primarily in the deep water slope area, which extends along the entire breadth of offshore Nova Scotia.

Salt Study

The Canada-Nova Scotia Offshore Petroleum Board has prepared a report of the deep water potential, looking at plays associated with salt features. Nova Scotia has seismic and geological attributes similar to other Atlantic-facing, look-alike deep water basins in the Gulf of Mexico, offshore Brazil and West Central Africa. The study is a geological basin evaluation and numerical assessment of the hydrocarbon potential of the deep water region. This slope region comprises some 31,000 mi^2 and extends some 530 mi from the boundary with Newfoundland and Labrador south to the Canada-United States border.

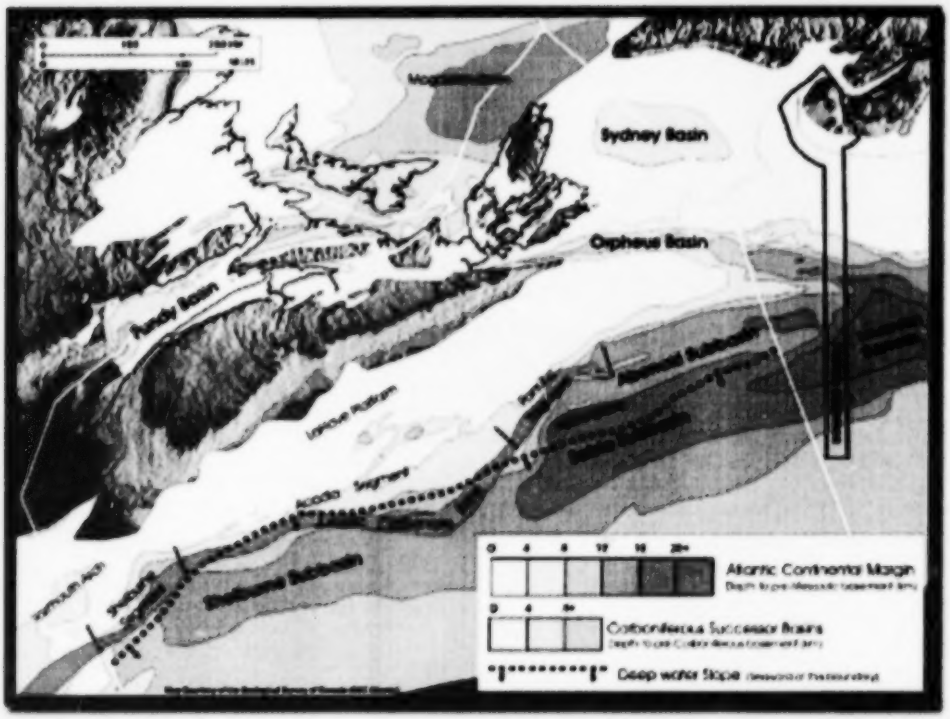
Some 18,650 mi of regional 2D seismic was used to correlate to wells on the Scotian Shelf and tie to older crustal seismic data. The focus of mapping was the mobile Jurassic Argo salt member. Some 12 play types were identified and mapped and included supra-salt minibasins, salt flank plays where the salt diapirs intersect Cretaceous and Tertiary aged sediments, and sub-salt features. Geochemical models examined known and inferred source rocks. Probability distributions were developed for oil, gas, solution gas and natural gas liquids for each of the 12 play types. Since there were no significant discoveries to validate the petroleum systems in deep water, geological risk was assigned.

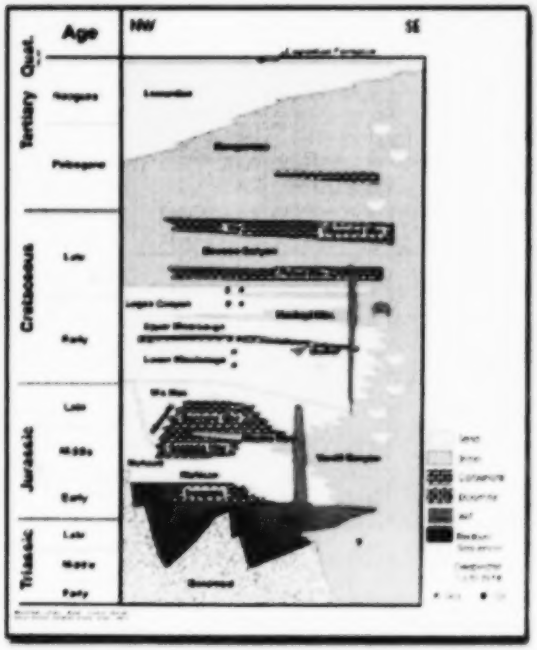
Resource Estimates

Resource estimates range from 15 - 41 Tcf and 2 - 5 billion barrels of oil. The oil potential is very significant and conforms to the high oil-to-gas ratios encountered in other deep water basins of the circum-Atlantic region. If the estimated ultimate recovery (EUR) per unit area for the Scotian Slope is calculated, it appears to be in line with other Canadian frontier regions such as the MacKenzie-Beaufort basin, the Labrador Shelf and the Sverdrup Basin of the Arctic Islands. If some or all of the 12 plays defined in the assessment are eventually proven, the slope region will have a much higher ranking and approach that of offshore Brazil in hydrocarbon richness per unit area.

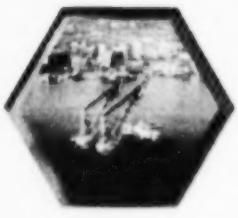
The impact of these numbers, on a risked basis, is to basically double the gas potential of offshore Nova Scotia while adding significant oil potential. Previous resource assessments showing 18 Tcf were made by the Geological Survey of Canada and did not include the slope areas. This study suggests the slope acreage could contribute an additional 15 Tcf of gas and 2 billion barrels of oil.

Opportunities





- Sable and Abenaki Subbasins
- Deep Water Slope
- Jurassic Carbonate Bank
- Shelburne Subbasin
- Orpheus Basin



Opportunities

The current exploration cycle has slowed and has resulted in a significant amount of prospective offshore land being returned to the Crown. These Crown lands lie in the Sable, Abenaki and the Shelburne Subbasins, the deep water slope region, with prospective Crown lands also available in the Orpheus Basin. Two other basins, the Fundy (late Triassic-early Jurassic syn-rift) and the Sydney (late Carboniferous sag) Basins contain petroleum opportunities but are less understood and riskier than other offshore basins (only two wells in each). Further work is ongoing to help better understand their basin architecture and geologic history in an effort to unravel their petroleum potential.

The Scotian Basin comprises a series of connected depocentres initially formed during the rifting stage that preceded the breakup of the supercontinent of Pangea starting in the middle Triassic. The basins' histories record the entire sequence of Atlantic-style rifting and formation on the wide offshore margins with maximum sedimentation during the late Jurassic and Cretaceous.

This entire Basin is still at a relatively immature stage of exploration. Recent exploration activity has been conducted in the Sable & Abenaki Subbasins, Upper Jurassic carbonate bank and the deep water slope resulting in some success. On the shallow shelf, PanCanadian (EnCana) discovered the Deep Panuke field in 1999 situated on the Abenaki carbonate bank. The discovery was followed by five successful delineation wells which all tested in excess of 50 MMcf/d on DSTs with net pay values ranging from 100-328 ft. On the deep water slope, an undelineated Upper Cretaceous gas discovery was made by Marathon in 2002 with its Annapolis G-24 well in 6035 ft of water.

The acquisition of new seismic datasets, particularly 3-D and regional programs, and the latest well information from recently released wells together provide new insights on the region's geology and petroleum systems. These new data and the Canada- Nova Scotia Offshore Petroleum Board's current large archival holdings of well and seismic data, combined with progressive Board policies provide an excellent information base with which to assess exploration opportunities. With just 130 exploration wells drilled and the many significant discoveries made, it is clear that much potential exists for successes in current and future hydrocarbon play types, many of which have not been tested.

The following details the petroleum potential for four areas in the Scotian Basin where large tracts of Crown lands are available for nomination.

opportunities

Sable & Abenaki Subbasins

In the Sable Island area during late Jurassic to early Cretaceous time, an extensive delta system developed at the mouth of the paleo-St. Lawrence River. The Sable Delta was a complex series of prograding delta wedges dominated by both wave and tidal forces. Tremendous volumes of mature sediments were sourced from the adjacent Upper Paleozoic age Maritimes Basin (Gulf of St. Lawrence) and the resultant fluvial, deltaic, strandline and marine sedimentation dominated much of the eastern and central Scotian Shelf area (Mic Mac and Mississauga Formations respectively). From about middle Jurassic time the delta first rapidly filled the eastern Laurentian Subbasin and then in the late Jurassic and early Cretaceous shifted its locus of deposition steadily southwestward to the Abenaki and Sable Subbasins. It eventually overwhelmed the coeval Abenaki carbonate bank complex in the Sable Island area. The accumulation of Mesozoic and Cenozoic age sediments in these latter two basins reaches thicknesses in excess of 13.5 mi without major unconformities.

The Sable and Abenaki Subbasins have been the focus of much of the petroleum exploration over the past forty years. To date, 24 gas and oil discoveries have been made in the offshore Nova Scotia region, mainly in the Sable and Abenaki Subbasins near Sable Island. The majority of these discoveries involve rollover anticlinal structures associated with down-to-basin growth faults. Reservoirs are deep and overpressured in structures situated in proximity of Sable Island, and shallower and normally pressured reservoirs south of Sable Island along the delta's distal margins.

The overpressured reservoirs occur in sandstones of the Upper Jurassic Mic Mac and Lower Cretaceous Mississauga Formations. Over 375 ft of net gas pay within 15 reservoirs have been recorded in one well in the Venture field – the largest discovery to date. Gas in the normally pressured sandstones is situated in the upper member of the Mississauga Formation. Gas also occurs in several additional reservoirs, including the Upper Cretaceous Wyandot (chalk) and Dawson Canyon (deltaic) Formations, and Middle Cretaceous Logan Canyon (deltaic) Formation indicating further potential in many different play trends.

Between 1995 and 2000, Mobil Oil Canada (now ExxonMobil) and Shell Canada pooled their existing significant discoveries into an economic joint venture known as the Sable Offshore Energy Project (SOEP) which began gas production on December 31, 1999. SOEP is a $3 billion project involving the development of six major gas fields that lie near the edge of the Scotian Shelf south of Sable Island. Phase I of the project was completed at a cost of $2 billion and encompassed the development costs of the Thebaud, North Triumph and Venture gas fields, subsea pipeline, gas plant at Goldboro, natural gas liquids pipeline to Point Tupper and a fractionation plant at Point Tupper. Phase II is underway for the remaining three fields, with Alma in production on December 3, 2003 and South Venture scheduled for late in 2004.

Nova Scotia is strategically located adjacent to the major energy markets of northeastern North America. The SOEP production is going to markets in eastern Canada and the U.S. Northeast. The SOEP fields are also producing natural gas liquids in the range of 20,000 bbls/day and are processed at a liquids handling facility in the Point Tupper area. In the short term, several of the gas discoveries that have been made in the vicinity of the SOEP project may be tied in to it to maintain production levels as they are very attractive to produce through the current infrastructure.

A report released by the Canadian Gas Potential Committee in 2001 shows 8.9 Tcf of discovered gas in place in the Sable Subbasin while 8.1 Tcf of gas remains undiscovered in this Subbasin. An undiscovered gas potential of 7.1 Tcf was also assigned to the Abenaki Subbasin. These numbers were generated using the CNSOPB's 1997 evaluation.

A large endowment of potential gas, condensate and oil resources has been predicted for the offshore Nova Scotia shelf region and the slope down to the ~5000 foot isobath. The last detailed gas resource evaluation was done by the Geological Survey of Canada in 1983 and predicted a mean probability of 18.1 Tcf of gas, 370 MMbbls of associated condensate and 710 MMbbls of oil. Analysis indicates that many attractive exploration targets remain in these subbasins and on the Shelf, particularly for gas pools in the range 200 Bcf to 1 Tcf.

Deep Water Slope

Since the late 1990s, Nova Scotia has seen a resurgence of exploration activity being directed at acreage that lies in water depths greater than 3200 ft along the Scotian Slope. The Slope region covers an area of about 31,000 mi^2 extending about 530 mi along the entire breath of offshore Nova Scotia. The catalyst for this exploration has been the successes in other deep water passive margins around the world including the Gulf of Mexico, offshore Brazil and West Central Africa. Industry has recognized that the Nova Scotia slope also shares the same geological attributes identified in other successful exploration and producing Atlantic Margin deep water regions. These attributes include production in the adjacent up-dip, shallow water region (Scotian Shelf SOEP Project), a large, ancient, sand-rich delta system (Sable Delta), and a mobile salt substrate (Argo Fm.)

The Canada-Nova Scotia Offshore Petroleum Board prepared & released a detailed assessment report in October, 2002 for the deep water potential and defined 12 play types associated with salt features. Prior to the report, Marathon Oil Company spudded a well in 5500 ft of water to test their Annapolis prospect. The B-24 well experienced a well control incident caused by an influx of gas believed to be from the shallow late Cretaceous Wyandot chalk. The well was abandoned and immediately repositioned. The Annapolis G-24 well was drilled to planned TD and encountered approximately 100 ft of net gas pay over several zones. This first discovery in the deep water provides confidence that this portion of the Slope region contains an active petroleum system. However, further evaluation is required to determine the commerciality of this discovery.

Since then, four more modern deep water wells were drilled by three different operators to the west of the Annapolis discovery but with little success. Given the availability of modern 3-D seismic coverage, the fact that there are many prospects and leads interpreted from the new datasets, and that multiple play types remain untested, there are numerous exploration opportunities present in the deep water for the aggressive explorer.

Opportunities

Jurassic Carbonate Bank

From the Middle Jurassic to Early Cretaceous, an extensive carbonate bank margin was formed along the North Atlantic margins. In the Scotian Basin offshore Nova Scotia, the carbonate platform extends 420 mi from the Canada-US border in the southwest to the Sable Island Area on the Scotian Shelf. It continues intermittently along the northeastern Shelf over to the southern Grand Banks of Newfoundland.

The Abenaki carbonate bank developed along the ancient rift margin hinge-line in the Middle Jurassic. The bank displays several margin profiles types ranging from steep escarpment to ramp-like. These attributes were used to divide it into three segments: Panuke, Acadia and Shelburne. Beyond Sable Island to the northeast, the carbonate shelf changes into a gently dipping ramp margin. In the region west of Sable Island, a total of 20 exploration wells have been drilled from 1970 to 2004; nine on the bank edge, nine on the landward interior platform and two on the foreslope. Seven play types have been identified across the Abenaki platform and margin and several have been tested, though in some cases by a single well. The CNSOPB has completed a study of the carbonate bank. Subject to approvals, a report may be released in early 2005.

The Panuke Segment is the best understood of the three and is where a commercial oil project and the Deep Panuke gas discovery are located. This region is relatively undisturbed by erosion and faulting and is juxtaposed against the prolific Sable Delta, which contains all but two of the 24 discoveries to date, and is the site of the current offshore gas production.

The Abenaki bank margin was first drilled in 1973. The target was structural closure at depth and although the Abenaki carbonates were wet, an up-hole oil discovery was made in overlying draped sands of the Cretaceous Logan Canyon Formation. This discovery became the Cohasset/Panuke oil project that produced 44 million barrels of light gravity 55°API crude from 1992-1999. These types of low-relief simple closure fields are very attractive due to the high productivity of the sandstones, location in shallow water and in moderate metocean conditions. Similar shallow oil accumulations should be found in other areas of the extensive carbonate bank and a large scale 3-D seismic dataset will certainly allow better imaging of these subtle traps.

Subsequently, a further eight wells were drilled in the 1970s along the bank margin until PanCanadian (EnCana) discovered the Deep Panuke gas field in 1999 drilled from the existing Panuke oil production platform. The main gas reservoir is a dolomitized and leached limestone reef margin facies near the top of the thick Baccaro Member. The reservoir has impressive properties: porosities of 3-40%, permeabilities of 1 md to several darcies and net pay values from 100-328 ft. Flow rates for the six wells including the discovery well have ranged from 50 – 63 MMcfd. Traces of H_2S were also encountered at concentrations of about 0.2% (~2000 ppm).

The above reservoir information shows that the Deep Panuke type of carbonate reservoirs can be excellent producers although they have high variability in reservoir characteristics. Because the play is based on seismic attributes, they are also difficult to find. With the Deep Panuke discovery, the existence of other fields along the Panuke Segment and/or extension of the current discovery is considerably enhanced.

The Acadia Segment was penetrated by three wells drilled during the 1970-1980 period. This region displays a more complex geological history than the Panuke segment, involving faulting, erosion and salt disruption. The positive aspect of this segment is that all three wells drilled in this area (Bonnet, Albatross and Acadia) encountered degrees of lost circulation indicating potential porosity zones, but incomplete mud gas logs and few DST's make it impossible to conclusively evaluate the potential and significance of these zones. A continuous grid of 3-D seismic is required over the Acadia Segment bank margin to fully evaluate the reef potential in this area.

The Shelburne Segment of the Abenaki bank margin is discussed in the Shelburne Subbasin section that follows below.

Shelburne Subbasin

The Shelburne Subbasin was a major center of deposition in the southwestern portion of the Scotian Basin. The Subbasin saw rapid deposition throughout the Jurassic and lesser infill during the Cretaceous and Tertiary, resulting in a cumulative thicknesses of 7.5 mi.

The Shelburne Subbasin contains carbonate bank opportunities in both the Acadia and Shelburne segments. A discussion of the Acadia Segment is included in the carbonate bank section.

The Abenaki carbonate of the Shelburne Segment has been unexplored with only some older regional seismic coverage but no wells. Seismic in this area shows a faulted rimmed carbonate platform with a steeply dipping foreslope. To the northeast, seismic shows the carbonate margin buried by a thick Cretaceous section with listric down-to-basin faults very close to the bank edge and fore slope. These structures offer exploration opportunities in the bank complex although new seismic data is required to better define the margin itself and related structures.

Thick salts are also present in the deep water portion of this subbasin. The 12 plays identified by the CNSOPB's 2002 Deep Water Scotian Slope Resource Assessment are associated with the salt and provide many opportunities to the explorer. A continuous 3-D seismic dataset will be necessary to fully evaluate these opportunities prior to drilling a well.

Orpheus Basin

The Orpheus Basin forms a structural trough on the northern Scotian Shelf, widening and plunging eastward from nearshore to the Laurentian Subbasin. Interpretations of industry seismic and magnetic data indicate that the northern margin of the Orpheus Basin coincides with the boundary between the Appalachian Avalon and Meguma terrains. The northern margin of the basin is bounded by the eastern extension of the Cobequid-Chedabucto fault with approximately 5 mi of vertical displacement. The southern margin consists of a series of discontinuous faults antithetic to e Cobequid-Chedabucto fault. Thick sedimentation into this basin was received during pre-breakup time and was filled by Middle Jurassic time.

The rift-fill sequence of the Orpheus Basin was comprised of mostly Triassic to Jurassic Mesozoic sediments which were deposited unconformably on a basement comprised of various lithologies and age including metasedimentary, metavolcanic, igneous intrusive, siliciclastic, carbonate and evaporate rocks. Seven exploratory wells were drilled in this basin in the 1970s primarily on structures at the basin margins or on poorly defined salt structures.

The Eurydice Formation overlying basement is the deepest target in the Orpheus Basin and is designated as Late Triassic redbeds. No wells have been drilled through the entire basin-fill sequence predicted to be approximately 6 mi thick. The type section for the formation is the Eurydice P-36 well which penetrated only the upper 200 ft of the formation, leaving approximately 6600 ft of the formation untested. This lower section of the Eurydice Formation in the Orpheus Basin could comprise the same coarse, presumably alluvial facies that has been drilled in the lower part of the Eurydice Formation in the Emerald Basin on the Scotian Shelf.

This basin has not been adequately explored and the petroleum potential is not well understood. The basin holds the potential for shallower, salt-related and deeper play opportunities especially in the lower portion of the Eurydice Formation. Additional close grid seismic needs to be acquired to better detail these plays particularly beneath the thick salt prior to drilling a well.

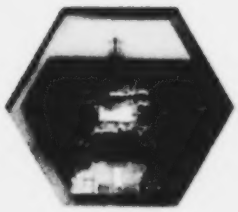
A report released by the Canadian Gas Potential Committee in 2001 attributes 1.3 Tcf of risked undiscovered gas potential to the Orpheus Basin.

Efficiencies

Atlantic Energy Roundtable

Results:

- Clarity, certainty and predictability of regulatory framework
- Shorter regulatory cycle times
- Lowering exploration costs
- Goal based regulation
- Maintaining environmental and safety standards



Atlantic Energy Roundtable (AER) – Regulatory Regime

Two years ago, three governments (Nova Scotia, Newfoundland and Labrador, and the Federal Government) met with industry to establish a forum to discuss regulatory improvements and opportunities for increased industrial activity in the Atlantic Canada offshore energy sector. As a result of that meeting, senior industry, government and regulatory officials established the Atlantic Energy Roundtable. The groups quickly established a program of consultation and research to discover where the opportunities for improvement lay.

The formal structure of the AER reflects the dual nature of the challenge. A Regulatory Issues Working Committee is a collaborative effort to identify potential changes in the offshore regulatory system that will improve Atlantic Canada's competitive advantage. An Industrial Opportunities Working Committee brings government and industry partners together to seek new industrial opportunities that come with offshore oil and gas development.

All Atlantic Energy Roundtable participants are committed to the development of Atlantic Canada's offshore energy resources in a safe, economically competitive, environmentally and socially responsible manner to the benefit of all stakeholders.

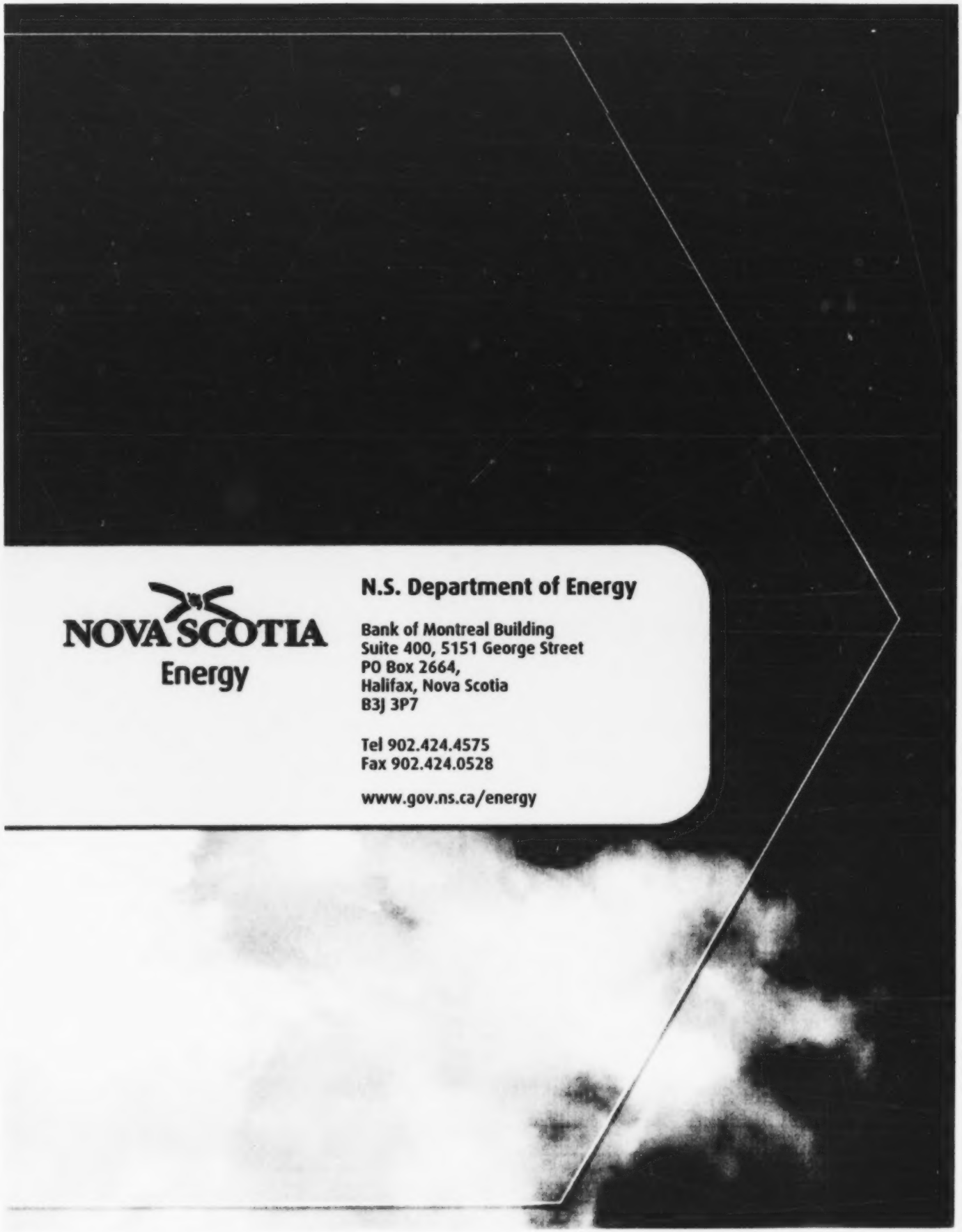
In the area of Regulatory Issues, the following results have already been achieved:

- a clearer and more certain regulatory environment
- a reduction in cycle-time for regulatory approvals for development projects

Current endeavors include:

- regulatory changes to make drilling requirements more flexible resulting in a significant reduction in potential drilling costs
- development of a common standard of practice for the mitigation of seismic impact consistent with international requirements
- review and revision of offshore regulations to bring them up to date and achieve more flexibility through the introduction of a "goal-oriented" approach to regulation, a form of performance-based regulation.
- an examination of regulatory requirements in the use of foreign registered mobile offshore drilling units (MODU's) and seismic vessels

The next meeting of the AER is scheduled for the **First Quarter of 2005** in Halifax, Nova Scotia.



NOVA SCOTIA
Energy

N.S. Department of Energy

Bank of Montreal Building
Suite 400, 5151 George Street
PO Box 2664,
Halifax, Nova Scotia
B3J 3P7

Tel 902.424.4575
Fax 902.424.0528

www.gov.ns.ca/energy